BOSTON EDISON COMPANY
CAMBRIDGE ELECTRIC LIGHT COMPANY
COMMONWEALTH ELECTRIC COMPANY
d/b/a
NSTAR ELECTRIC

REBUTTAL TESTIMONY OF CHARLES P. SALAMONE

D.T.E. 03-121

Q. Please state your name and business address.

A. My name is Charles P. Salamone. I am Director of System Planning for the electric subsidiaries of NSTAR Electric, with an address of One NSTAR Way, Westwood, Massachusetts.

Q. On whose behalf are you submitting testimony in this proceeding?

A. I am submitting rebuttal testimony on behalf of NSTAR Electric.

Q. Please describe your education and professional background.

A. I hold a Bachelor of Science Degree in Electrical Engineering from Gannon University. I joined the Engineering Department of Commonwealth Electric Company in July of 1973. At that time, I became a Junior Planning Engineer where my primary responsibilities were to assist in the planning, analysis and design of the transmission and distribution systems of the company. I generally followed the normal progression of positions with increasing levels of responsibility within the planning area until taking my current position in 2000. I have recently served as Chair of the NEPOOL Planning Policy Subcommittee (1997-1998), Chair of the NEPOOL Regional Transmission Planning Committee (1998-1999) and Vice Chair of the NEPOOL Reliability Committee (1999-2000). I am a Registered Professional Engineer with the Commonwealth of Massachusetts. I am also a member of the Power Engineering Society of the

Institute of Electrical and Electronic Engineers. A copy of my resume is attached hereto as Exhibit NSTAR-CPS-2.

Q. Have you previously testified before the Department or other regulatory agencies?

A. Yes. I have previously testified before the Federal Energy Regulatory Commission, the Department of Telecommunications and Energy and the Energy Facilities Siting Board on a number of technical matters relating to system planning.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to rebut some of the erroneous statements that intervenor witness have made regarding the manner in which NSTAR Electric plans for customers with distributed generation ("DG"). Many of the intervenors appear to misunderstand how a distribution company must plan its distribution system in order to provide reliable electric service and, by implication, how costs are incurred to serve customers. In my rebuttal testimony, I explain how distribution systems are planned and how the presence of customer-owned generation affects those planning decisions.

Q. What statements made by intervenors do you believe are erroneous?

A. Several of the intervenors have stated that the configuration of an electrical distribution system designed for all-requirements customers is different from a distribution system that includes a DG customer that requires firm standby service. For example, Mr. Lively, Mr. Casten and Mr. Smith state that the presence of self-generation reduces the need for distribution system upgrades, thus providing cost savings. Ms. Saunders erroneously confuses the concepts of so-called "shared" facilities with the fact that investments made on behalf of standby customers are fixed and unavoidable. In addition, Mr. Pereira argues that DG and energy efficiency measures have similar impacts on distribution-system planning and should therefore be treated similarly for ratemaking purposes. As described below, from an engineering and planning perspective, the costs that must be incurred by a distribution company to provide reliable distribution service for a firm standby customer are generally the same as an all-requirements customer that has a similar-sized internal load.

Q. How does the Company design its distribution and transmission systems?

A. In general, the Company establishes different planning criteria for transmission facilities, substations and local distribution segments of the system. Exhibit NSTAR-CPS-3 is a diagram that illustrates the major portions of the electric transmission and distribution system.

Q. Please describe Exhibit NSTAR-CPS-3.

A. Exhibit NSTAR-CPS-3 is a graphic showing the primary components of an electric delivery system. It begins with a power generating station that steps up its output voltage to higher levels for transmission across the system. This output is carried by the transmission system for delivery to substations where the voltage is reduced for delivery to the distribution system. The power is then carried by the distribution system to distribution transformers which further reduce the voltage for delivery to customer loads. For the NSTAR Electric system, typical transmission voltages range from 345 kV down to 115 kV and typical distribution voltages range from 23 kV down to 4 kV. Customer loads typically operate in the 480 V to 120 V range. Sufficient capacity must be maintained through each element of the delivery system to ensure adequate supply capabilities.

Q. What are the planning criteria for local distribution segments of the system?

A. Starting from the customer meter, to the customer drop through the supply transformer and distribution feeder circuit, the capacity of the equipment is designed so that no element is loaded beyond its normal rating based on the non-coincident peak demands of all customers on the circuit. Equipment ratings are established by equipment manufacturers and are based primarily on the thermal limitations of equipment as a result of the electrical loads that the equipment is carrying. Generally, normal ratings are based on the continuous load carrying capability of equipment.

Q. How does the Company forecast the peak demand at the circuit level?

A. The process for determining the expected peak load on a distribution circuit considers the existing peak load, projected peak load increases and unavailability of any generating sources that are connected to the distribution circuit. Existing peak load values for each distribution circuit are monitored and hourly load data is maintained within company computer databases for the prior two years. This information is combined with projected peak load additions to establish the projected normal and emergency (i.e., loss of supply) loading conditions that each circuit could be exposed to. The expected growth of existing and incremental load additions is captured through a projection based on area econometric factors as well as weather sensitivities. Peak load conditions are heavily driven by weather conditions. Extreme weather conditions invariably lead to peak load conditions. Customer peak demands during these conditions exhibit very little diversity from their individual peak demands with diversity factor values ranging from 95 percent to 100 percent. Expected non-coincident customer peak demands are explicitly tracked and load increases above 1 megawatt ("MW") are added to the forecast data to establish a projected circuit peak demand. Our basic assumptions for load forecasts are that loads below the 1 MW load level are captured in the econometric-based forecasts and are of a size that is below the level of accuracy that circuit load information can reasonably be projected. The weather extreme projected peak demand is generally very close to the non-coincident peak demand of the customers served by each distribution circuit. These results are compared to the load carrying capabilities of the delivery system under both normal and emergency conditions. The end result of these considerations is that the capacity requirements for the distribution system are planned to effectively serve the non-coincident peak load of all of the customers served by each distribution circuit.

Q. What are the planning criteria for substations?

A. At the substation level, the Company's planning criteria require that at peak load, no element of the substation, e.g., transformer or circuit breaker, can exceed its normal rating and that, if there is a loss of one element, the remaining elements will not exceed their emergency capacity rating. The emergency rating of equipment is the limited time duration load-carrying capability of the equipment. The emergency rating is employed only during the limited time intervals that occur when other elements of the system are out of service. For example, if there is the loss of a transformer at a substation, the load is typically transferred to adjacent transformers. The adjacent transformers would carry both their normal load and some or all of the load normally carried by the failed unit. The ratings employed under this condition are the emergency ratings of all remaining equipment. The emergency rating of equipment is higher than the normal rating and can be employed only for a limited time period which is generally 12 hours or less during a single load cycle. The criterion for design of the system is that the peak load at a substation should not exceed the emergency rating of the substation when any element is out of service.

Q. **How does the Company forecast the peak demand for substations?**

A. The peak demand forecast for a substation is obtained through a substation-based load projection process that considers the supply area characteristics and growth expectations for the loads served by the substation. This begins with assessing the non-coincident peak load of a substation (which is the coincident peak demand of the circuits supplied by the substation) by monitoring each transformer within the station, adding expected area load growth, and adding specific projected large load increases (individual customer load increases over 1 MW are explicitly tracked). For DG units of 1 MW or more, loads normally supplied by customer generation are also added to these values based on the potential unavailability of that generation during peak load conditions. The loading on substations also exhibits limited diversity between the coincident and non-coincident loading of the circuits supplied by a substation. Diversity factors for substations are generally lower than they are for individual circuits, but remain in the 92 to 98 percent range.

Q. What criteria apply to designing transmission facilities?

A. Transmission planning criteria are in conformance with the requirements of the New England Power Pool ("NEPOOL") and the Northeast Power Coordinating Council ("NPCC"), as well as internal criteria, which address more localized issues. In general, these criteria are similar to that employed for substation and distribution systems and consider that no element of the system should exceed its emergency load carrying capability when major system elements are out of service. Peak loads seen by the transmission system are a result of the coincident peak loads of the substation loads served by the transmission system. There is generally more diversity between the substation peak loads under extreme weather conditions because of the variability of the weather conditions across the service territory. These conditions vary more widely than they do for any individual substation or a given distribution circuit since weather conditions are generally not uniform across the service territory. Substation diversity factors generally range from 90 percent up to 95 percent. Flows on transmission system elements are a function of a number of factors in addition to substation loads because of the fact that transmission facilities are interconnected to numerous generating sources and external area loads. The peak load projected to be seen by transmission system elements can be determined only through load flow simulations that represent the load and operating conditions under which highest flows across that particular element could occur.

Q. How does the distribution planning process change with the presence of a distributed generation customer who requires standby service?

A. In order to be able to provide reliable service to all firm customers, the full, peak internal load of a standby customer must be included in the peak demand analysis for purposes of determining the size of capacity of the distribution system, unless there are multiple standby customers on a circuit or substation and the generation units are always operated, subject to random and non-coordinated, unavoidable unplanned or maintenance outages, when the customer needs the power. Alternatively, the distribution company must have the physical assurance that the DG units will be in operation (or the customer's load will otherwise be reduced by the amount of capacity represented by the DG units) if it is going to be able to rely on the existence of that capacity for purposes of distribution planning and constructing necessary facilities to meet projected loads. However, these circumstances do not currently exist on the NSTAR Electric distribution system.

Q. Could you explain the importance of physical assurance for DG units in more detail?

A. Yes. To the extent that a DG unit is subject to the operational decisions of individual customers (and not the distribution company), it cannot be relied on with the same certainty as other capacity elements of a distribution company's system. For example, customers do not have the obligation to serve like distribution companies do and they may choose to shut down DG facilities at any point in time based upon their own economics and resource constraints. High fuel prices, the opportunity to pursue fuel arbitrage options, maintenance scheduling and the unavailability of facility operations personnel may cause a DG customer to forego operating its DG unit at a given time, especially if it can rely on the backstop of the distribution company's system for providing continuous electric service. Because of these very real complications associated with DG, it cannot be treated by distribution planners on an equivalent basis from an available capacity perspective as other elements of a distribution company's system.

Q. Why isn't there any diversity value for the existence of a DG unit on a circuit?

A. If there is only a single DG unit on a circuit, the distribution company must have in place facilities to meet the internal load requirements of the customer, since it must plan for the possibility that the unit will be unavailable at the time of peak demand. This is precisely the way the Company must plan for all of its customers at the circuit level; it must have sufficient capacity to meet the non-coincident peaks of each of its customers. Thus, the cost to serve a DG standby customer is the same as the cost to serve any another customer with the same peak load. If, in the future, there were multiple DG standby customers on a circuit, there might be diversity value and resulting cost savings.

Q. How would there be value if there were multiple DG standby customers on a circuit?

A. If there were multiple DG standby customers on a circuit, portions of the feeder routes could be sized on the expectation that not all of the DG facilities would likely be unavailable at the same time. However, to alter the planning assumptions based on the average availability of multiple DG facilities, it is necessary that the DG customer agree to operate the generator as long as it is available and there is internal customer load to serve. If, as claimed by DG proponents, some generators can be available in excess of 80 percent of the time, they cannot be permitted to run the DG only 40 percent of the time in order, for example, to sell fuel at a large profit. Therefore, as described above, if 10 DG customers with gas-fired generators diverted their gas supplies during a time of high gas prices, there would be insufficient distribution capacity to serve all customers on the circuit and the electric distribution company would have improperly designed the system based on non-existent "diversity" value of the DG facilities. Diversity value of multiple DG standby customers must be predicated on the certainty of fuel supply, the scheduling of maintenance and the guaranteed availability of the units, except as a result of unavoidable outages.

Q. Do you have any other recent examples of how you consider the presence of DG facilities on distribution planning?

A. One relevant example of a DG application within the NSTAR Electric system can be found at the Massachusetts Institute of Technology ("MIT") campus. MIT has a 26 MW generating unit connected to its internal campus distribution system. This generation normally serves the entire campus load. NSTAR Electric provides backup services for this load and, in order to ensure that adequate supplies exist, the NSTAR Electric system is designed to supply MIT's peak demand loads even when the generating unit is out of service. This capacity is modeled to be potentially placed on the NSTAR Electric system under both normal and emergency conditions. To properly account for the MIT loads, a system capacity assessment is performed to ensure that sufficient emergency capabilities exist for projected peak loads when both a critical NSTAR Electric system element is out of service and the MIT generator is unavailable. The process for determining the loads that must be supported by the NSTAR Electric system requires that NSTAR Electric develop a peak load projection for the transmission system serving Cambridge, its Putnam substation serving the MIT area loads and the MIT connected distribution facilities based on system projected peak loads in combination with the MIT peak load even when the MIT generator is not running. This essentially is the same projected peak load that would occur if MIT did not have any on-site generation.

Q. Are there any other examples?

A. Other examples include other large customers that are considering installation of DG to serve their own loads. In these other examples, customers have introduced new load additions and have postulated new generation to serve this new load. NSTAR Electric has conducted system assessments that ensure that there is sufficient capacity on the system to serve this new load to protect for loss of or unavailability of the proposed generating unit. This capacity must be available during peak load emergency conditions to ensure that the capacity will be available whenever the customer needs it. This is the level of service that customers expect and it is what NSTAR Electric is obligated to provide. The upgrades have involved required construction of new distribution facilities to support the new loads and the substation load projections were also revised to include the customer load expansion. These actions were identical to those that would have been employed by NSTAR Electric had the customer simply added new load without considering addition of its own generating capabilities. On the NSTAR Electric system, such large generation additions provide customers with energy benefits, but do not avoid the requirement for the Company to provide sufficient system capacity at the circuit level and at substations to serve the projected customer peak loads under both normal and emergency conditions.

Q. Why are the assertions of the intervenor witnesses inconsistent with the way distribution facilities must be planned?

A. When an electric distribution system is designed, the internal load of the DG standby customer must be included in the peak demand used to determine the capacity of the circuit. If the customer's internal load is significant (1 MW or larger), the substation must also be of sufficient size to handle the full internal load at the time of the substation peak under normal and emergency conditions. This is because the distribution system must be ready and able to serve that large customer's internal loads during the peak, and like MIT, the distribution system planner must "size" the system (including substations) to meet that demand for whenever it may arise.

Q. What does this mean in relation to the costs incurred to serve a standby DG customer?

A. The distribution-system costs incurred to serve a non-interruptible customer with self-generation are no different from the distribution-system costs incurred to serve a similar customer without self-generation. This is because the distribution company must size its circuits to meet the peak load of the internal requirements of all customers (including those with self-generation in the event the self-generation is not available). At the distribution substation level, the distribution company must size substations to meet the peak load of the internal requirements of all customers (including those with self-generation in the event the self-generation is not available). For smaller DG customers of less than 1 MW, their size is small enough in comparison to the capacity of a typical substation to benefit from the diversity of the coincidence of peak loads served by the substation. For larger DG installations of 1 MW or more, they are specifically tracked and added in to the coincident peak load of the substation. These larger DG facilities are big enough that their operations can have a material impact on the operation of the distribution system and are explicitly modeled as part of the distribution planning process. Any diversity value of the presence of DG facilities would permit reduction in planning assumptions for load requirements (and corresponding cost savings) only if there were the physical assurance that the capacity of DGs would be available, aside from legitimate unplanned outages. These circumstances do not currently exist on NSTAR Electric's distribution system.

Q. Some intervenors state that DG is similar to energy efficiency ("EE") measures and therefore should be treated similarly for ratemaking purposes. Do you agree that DG should be treated similarly to EE measures?

A. No, I do not. EE measure represent a "permanent" (although normally smaller) change in a customer's internal load; that is, after installation, any lower customer demand resulting from the presence of low-wattage bulbs, insulation or high-efficiency motors does not suddenly disappear because of a catastrophic failure or temporary unavailability. Moreover, EE installations are numerous and diverse on all distribution circuits throughout the service territory. Therefore, there is significant diversity value in EE savings and the failure of one customer's relatively small EE measure will not have a material impact on the integrity of the distribution system. In contrast, DG eliminates a customer's load when it is in operation, but immediately returns to the distribution system at its full level of load when the DG is unavailable.

Q. **Please summarize your disagreement with the arguments made by intervenor witnesses.**

A. In summary, the distribution system must be designed and constructed to meet the internal demands of its customers. The planning process should include the internal load of DG standby customers in order to maintain system reliability. Thus, the costs incurred to provide firm standby distribution service for a customer with self-generation are no different from the costs to provide distribution service to another customer with similar internal load.

Q. **Does this conclude your testimony?**

A. Yes, it does.